Testimony of
Sarah E. Hardy

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR APPROVAL OF A CHANGE IN ITS	)	P.S.C. DOCKET NO. 13-
GAS SALES SERVICE RATES ("GSR")	)	
TO BE EFFECTIVE NOVEMBER 1, 2013	)	

DIRECT TESTIMONY OF SARAH E. HARDY

<u>On Behalf of Chesapeake Utilities Corporation</u>

<u>Delaware Division</u>

Submitted for filing: September 3, 2013

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Sarah E. Hardy and I am a Regulatory Analyst II with Chesapeake Utilities Corporation ("Chesapeake" or the "Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. BRIEFLY DESCRIBE YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Business Administration with concentrations in Management and Operations Management and a Minor in International Business from the University of Delaware in Newark, Delaware, in 2005. I received a Masters of Business Administration from the University of Delaware in Newark, Delaware, in 2009. I was hired by Chesapeake as a Regulatory Analyst II in June 2010. As a Regulatory Analyst II, I have primarily been involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the Delaware natural gas distribution company. Prior to joining Chesapeake, I was employed by Conectiv Energy Supply, Inc. from July, 2005 until May, 2010, most recently as a Senior Accountant. As a Senior Accountant, I was responsible for Conectiv Energy's derivatives accounting (including preparation of derivatives disclosures for SEC reporting), Federal Energy Regulatory Commission (FERC) filings, and other general accounting duties.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the mechanics of the three GSR charges, explain the development of the firm and interruptible sales volumes and total system requirements, and discuss the development of the unaccounted for gas volumes. In addition, my testimony will support the overall calculation of the Delaware Division's three proposed GSR charges to be effective with service rendered on and after November 1, 2013, as well as the mechanics of the Delaware Division's proposed balancing rates for transportation service under the Large Volume Service ("LVS"), High Load Factor Service ("HLFS") and Interruptible Service ("ITS") rate schedules. I will be illustrating the impact of the proposed GSR charges on an average residential customer's bill and ensuring compliance with the gas cost provisions outlined in previous Commission Orders.

Q. ARE THERE ANY SCHEDULES INCLUDED WITH YOUR DIRECT TESTIMONY?

A. Yes. My direct testimony includes Schedules A.1, A.2, B, C.1, C.2, D.1, D.2, E, F, G, H, I, J, L, M, and N. Schedule K, which is a comparison of Chesapeake's GSR rates with those of other utilities in the area, will be submitted under separate cover to the Commission within forty-five (45) days after filing this GSR application, as required by Order 7607 issued on July 7, 2009, in PSC Docket No. 08-269F.

Q. IS THE COMPANY FILING ANY OTHER DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. Chesapeake is also filing the direct testimony of Marie E. Kozel, Gas Supply Analyst II. Ms. Kozel will be presenting testimony regarding the Company's gas supply and procurement activities.

Q. WHAT PRESCRIBES THE METHODOLOGY FOR DETERMINING THE COMPANY'S GAS SALES SERVICE RATES?

A. The three Gas Sales Service Rates proposed to be effective with service rendered on and after November 1, 2013 have been developed in accordance with the approved gas cost recovery mechanism as contained in the Delaware Division's natural gas tariff, specifically Sheet Nos. 42 through 42.3.

Q. WHAT GAS SALES SERVICE RATE LEVELS ARE YOU PROPOSING IN THIS PROCEEDING TO BE EFFECTIVE WITH SERVICE RENDERED ON AND AFTER NOVEMBER 1, 2013?

A. The Company proposes the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2013: $1.008 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS, and LVS, $0.536 per Ccf for customers served under rate schedules GLR and GLO, and $0.819 per Ccf for customers served under rate schedule HLFS. Chesapeake is also proposing the following balancing rates to be effective for service rendered on and after November 1, 2013: $0.072 per Ccf for transportation customers served under rate schedule LVS, $0.015 per Ccf for transportation customers served under rate schedule HLFS, and $0.001 per Ccf for transportation customers served under rate schedule ITS.

Q WHAT EFFECT WILL THIS PROPOSED INCREASE IN THE GSR HAVE UPON THE AVERAGE RESIDENTIAL HEATING CUSTOMER?

A. As compared to the rates that were in effect November 1, 2012, an average RS-2 customer using 700 Ccf per year will experience an annual increase of approximately 0.7% or $0.64 per month. During the winter heating season, a typical RS-2 customer on Chesapeake's system using 110 Ccf per month will experience an increase of approximately 0.8% or $1.21 per winter month. A typical RS-2 customer using 120 Ccf per winter month will experience an increase of approximately 0.8% or $1.32 per winter month.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE PROPOSED GAS SALES SERVICE RATE LEVELS TO BE IMPLEMENTED IN THIS PROCEEDING.

A. The rates were calculated based on the estimated purchased gas costs and estimated sales volumes for the twelve months ending October 31, 2014 and are summarized on Schedule A.1. As shown on Schedule A.1, total projected firm gas costs recoverable through the gas cost recovery mechanism are $37,947,851. This total is comprised of $21,162,741 of fixed costs and $16,785,109 of variable costs. The three gas cost rates shown at the top of Schedule A.1, which include a fixed rate (used to calculate separate demand rates), a variable / commodity rate, and a total rate or system average rate, are the key components for calculating separate Gas Sales Service Rates for different services.

Q. CAN YOU BRIEFLY SUMMARIZE THE REASONS WHY THE THREE GSR CHARGES ARE CHANGING FROM THE COMPANY'S PREVIOUS FILING?

A. The analysis of the change in gas costs and Gas Sales Service Rates from the Company's last gas cost recovery filing is summarized on Schedule E. As shown on this schedule, variable or commodity gas costs are anticipated to increase by $1,362,028 since the last GSR filing. The variable costs contained in this filing are increasing primarily due to the projected cost of flowing commodity gas for the upcoming year increasing from the flowing commodity gas costs included in the previous GSR filing with rates effective on and after November 1, 2013 as well as an increase in projected volumes.

As shown on this schedule, fixed costs are anticipated to increase by $755,282 since November 1, 2012, the date of the last change in the Company's GSR. The increase in fixed gas costs is mainly attributable to changes in capacity entitlements, as discussed in the direct testimony of Marie E. Kozel.

This results in an increase in the system average cost per Ccf of $1.057 per Ccf in this filing versus $1.042 in the November 1, 2012 filing.

Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USED TO DETERMINE ITS GSR LEVELS AND THE VARIOUS COMPONENTS OF THE DELAWARE DIVISION'S GSR CALCULATIONS AS SHOWN ON SCHEDULE A.1.

A. Schedule A.1 is a summary of the calculation of the three proposed GSR levels. The calculations of the proposed GSR levels have been made in accordance with the provisions set forth in the Delaware Division's GSR tariff clause. The process to determine the GSR charges consists of three major steps:

1. Develop the sales and associated gas supply requirements forecast.
2. Forecast supplier rates and calculate annual purchased gas costs associated with serving the Company's firm sales customers.
3. Derive the GSR charges utilizing the results of the first two steps and the process below:

Step 3 is summarized on Schedule A.1. Initially, three gas cost rates must be established to calculate the three separate GSR charges: a fixed rate, a commodity rate and a system average rate. Based on total firm gas costs recoverable through the gas cost recovery mechanism for the GSR levels to be effective November 1, 2013, the three gas cost rates are calculated as follows:

Fixed Rate - $24.86/ Ccf	(Total fixed costs of $21,162,741 divided by the firm peak day capacity requirements of 851,380 Ccf)
Commodity Rate - $0.468 / Ccf	(Total firm commodity costs of $16,785,109 divided by firm sales volumes of 35,898,652 Ccf for the period November 2013 through October 2014)

System Average Rate - $1.057 / Ccf (Divide total firm gas costs of $37,947,851 by the firm sales volume of 35,898,652 Ccf)

From these three rates, different methodologies are applied in order to calculate the Gas Sales Service Rates that more closely align the Gas Sales Service Rates with actual gas costs identified for providing services associated with different rate schedules or customer classes.

Q. PLEASE EXPLAIN THE THREE METHODOLOGIES UTILIZED TO CALCULATE THREE SEPARATE GAS SALES SERVICE RATES USING THE FIXED RATE, COMMODITY RATE AND SYSTEM AVERAGE RATE AS PREVIOUSLY DESCRIBED.

A. Schedule A.1 also provides a summary of the development of the three separate Gas Sales Service Rates by applying the tariff language described in the Delaware Division's tariff on Sheet No. 42.2.

<u>Rate Schedule HLFS</u>

This GSR charge, applicable to any customer qualifying for High Load Factor Service (HLFS), is calculated based on the combination of a weighted average demand and commodity rate developed on an overall 60.83% load factor for the customer class and the overall system weighted average cost rate. The 60.83% load factor is included on Schedule J. This means that the fixed gas cost rate of $24.86 per Ccf, as previously described, is divided by 222 days (60.83% of 365 days in a year) to calculate a demand rate of $0.112 per Ccf. This rate is then added to the commodity rate, as previously described, of $0.468 per Ccf to calculate a volumetric rate of $0.580 per Ccf. The arithmetic average of this volumetric rate ($0.580 per Ccf) and the system average rate ($1.057 per Ccf) is $0.819 per Ccf, which equals the GSR charge for HLFS customers. Total costs associated with HLFS ($2,291,780) are projected by multiplying the GSR charge ($0.819 per Ccf) by the projected sales volumes for HLFS (2,798,266 Ccf).

<u>Rate Schedules GLO and GLR</u>

All customers served under these Gas Lighting rate schedules will be subject to the same GSR charge. This rate is calculated using weighted average demand and commodity rates through a single gas cost rate per Ccf, based on a 100% load factor. The demand rate of $0.068 per Ccf ($24.86 / 365) plus the commodity rate of $0.468 per Ccf, produces a GSR charge of $0.536 per Ccf. Total costs associated with Gas Lighting Services of $665 are a result of multiplying the $0.536 per Ccf GSR charge by the annual sales volumes for these services of 1,240 Ccf.

<u>Rate Schedules RS-1, RS-2, GS, MVS and LVS</u>

These rate schedules are assigned the remaining firm purchased gas costs after the firm purchased gas costs have been calculated for the above mentioned rate schedules ($37,947,851 - $2,291,780 - $665 = $35,655,406). Associated costs are divided by the remaining volume (35,898,652 – 2,798,266 – 1,240 = 33,099,146) to develop a rate of $1.077 per Ccf, less the portion of any shared margins ($0.069 per Ccf) as shown on Schedule A.2. All customers served under rate schedules RS-1, RS-2, GS, MVS and LVS will be charged $1.008 per Ccf for service rendered on and after November 1, 2013.

Q. PLEASE DEFINE THE TERM "SHARED MARGINS".

A. Shared Margins are defined as any margins that the Company receives as a result of interruptible transportation service, off system sales or capacity releases. There are different thresholds for sharing each type of margins received.

Q. PLEASE DESCRIBE THE EFFECTIVE MARGIN SHARING PERIOD AND THE THRESHOLDS THAT HAVE BEEN APPROVED BY THE COMMISSION.

A. Pursuant to the settlement agreement reached in PSC Docket 12-450F, the Company will retain 7.5% of all capacity release credits received from the Company's Asset Manager and credit 92.5% to the firm ratepayers. Also, as outlined in the settlement agreement reached in PSC Docket No. 09-398F, the Company is permitted to retain 100% of all interruptible transportation margins up to $675,000 per year and 10% of all interruptible transportation margins over $675,000 per year. As shown on Schedule A.2, the Company is not projected to reach the sharing threshold for interruptible transportation margins in this twelve month determination period. Schedule A.2 does show the calculation of the $0.069 per Ccf margin sharing rate, proposed to be effective November 1, 2013, as a result of the sharing of the capacity valuation credit from the Asset Manager. The Company is not projecting any off system sales for this determination period.

Q. IN THIS FILING, WAS THE FULL BENEFIT OF PROJECTED CAPACITY RELEASES TO TRANSPORTATION CUSTOMERS ON EASTERN SHORE NATURAL GAS COMPANY'S ("EASTERN SHORE") SYSTEM CREDITED TO THE DELAWARE DIVISION FIRM RATEPAYERS?

A. Yes. The Company believes, as stated in prior GSR filings, that crediting 100% of the revenue received from capacity released to the Delaware Division's transportation customers to the firm sales customers is appropriate due to the market on Eastern Shore for this capacity. The Company has estimated this capacity release value to be $4,770,740 for the twelve-month period ending October 2014 as calculated on Schedule I and shown as a reduction to fixed demand costs on Schedule B. The total peak day firm entitlements on Eastern Shore are projected to be 71,754 Dts per day for this determination period of which 17,944 Dts per day of Daily Contract Quantity entitlements are projected to be released to transportation customers, or approximately twenty-five percent (25%) of the Delaware Division's peak day capacity on the Eastern Shore pipeline.

Q. AS INDICATED IN YOUR TESTIMONY, THE FIRST STEP IN CALCULATING THE PROPOSED GSR CHARGES IS THE DEVELOPMENT OF THE SALES AND ASSOCIATED GAS SUPPLY REQUIREMENTS FORECAST. HOW ARE THE SALES AND SUPPLY REQUIREMENTS FORECASTS DEVELOPED IN THIS PROCEEDING?

A. A forecast of purchased gas costs must start with a forecast of demand or sales volumes for the Company's distribution system. Based on meeting the sales forecast, the Company develops a forecast of the associated purchases or supply requirements. For the purpose of this proceeding, the sales forecast began with an analysis of the major variables that affect sales volumes. These variables include such items as the number of customers to be served, the rate schedule classification of those customers (i.e. large volume, high load factor, etc.), temperature, and the larger individual commercial and industrial customer sales volumes or demands. Sales volumes are normalized based on a ten-year average of degree days for the months of July 2004 through June 2013.

Q. HAS A SCHEDULE BEEN INCLUDED SETTING FORTH THE ESTIMATED VOLUMES OF GAS TO BE BILLED TO CUSTOMERS DURING THIS PERIOD?

A. Yes. Schedule C.1 shows Chesapeake's projected sales volumes by customer class for the determination period of the twelve months ending October 31, 2014.

Q. PLEASE DISCUSS FURTHER THE DEVELOPMENT OF THE SALES FORECAST SHOWN ON SCHEDULE C.1

A. Forecasted sales were used for the entire twelve-month period of November 2013 through October 2014. Forecasted sales were developed based upon the actual sales volumes billed to each customer class during each month for the prior year with adjustments to reflect average temperature, customer growth and customers switching among rate classes.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE TWO RESIDENTIAL SERVICE CLASSES?

A. For the twelve month period ending October 31, 2014, the Company has projected an increase of approximately 1,690 RS-2 customers over the current GSR determination period, with the majority of the increase representing growth in new customers. For the twelve month period ending October 31, 2014, the Company has projected a decrease of approximately 249 RS-1 customers from the current GSR determination period. This decrease is primarily the result of reclassification of customers from RS-1 to RS-2.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE FIRM COMMERCIAL AND INDUSTRIAL CLASSES?

A. With respect to the Commercial and Industrial customers, the Company projects an overall increase of approximately 128 customers over the previous twelve-month period.

Q. PLEASE DISCUSS ANY OTHER FIRM CUSTOMER ADJUSTMENTS.

A. With respect to the number of Gas Lighting customers, no significant changes are projected during this twelve-month period.

Q. DOES THE COMPANY HAVE ANY PROJECTIONS FOR THE NUMBER OF FIRM COMMERCIAL AND INDUSTRIAL CUSTOMERS THAT MAY CHOOSE

TO TRANSPORT ON ITS DISTRIBUTION SYSTEM AND THE VOLUMES ASSOCIATED WITH THESE CUSTOMERS FOR THIS PERIOD?

A. Yes. The Company has not included in its projections any firm commercial or industrial customers switching from sales service to transportation service during the determination period. This filing includes projections for gas to be transported on the Company's distribution system for those customers who are currently receiving transportation service based on the Company's current eligibility requirements, as well as new natural gas customers that the Company anticipates will choose transportation service. There are 266 firm commercial / industrial customers and two (2) interruptible commercial / industrial customers who will be transporting their own gas on the Delaware Division's distribution system. The Company has estimated the firm commercial / industrial transportation volumes to be approximately 3,843,569 Mcf and the interruptible commercial / industrial transportation volumes to be approximately 95,560 Mcf during this period. The estimated firm commercial / industrial transportation volume is an increase over the projection from the previous GSR filing which was 3,579,385 Mcf.

Q. PLEASE EXPLAIN HOW THE PROJECTED SALES VOLUMES WERE USED TO CALCULATE THE ASSOCIATED GAS SUPPLY REQUIREMENTS NEEDED BY THE DELAWARE DIVISION DURING THE DETERMINATION PERIOD.

A. Using the projected sales volumes from Schedule C.1 as a starting point, adjustments due to cycle billing, unaccounted for gas, pressure compensation and company use gas were derived in order to calculate the total gas supply requirements for the period.

Q. PLEASE EXPLAIN THE CYCLE BILLING ADJUSTMENT AS SHOWN ON SCHEDULE C.1.

A. All sales volume projections included in this GSR filing are associated with a respective billing month while the Delaware Division's purchases are recorded on a calendar month basis. Chesapeake includes a cycle billing adjustment in its calculation of the GSR charges for the purpose of accounting for the difference between a billing month and a calendar month. The cycle billing adjustment is calculated by first dividing the projected, normalized firm sales volumes for each month into a base load and a heating load. The heating load is then multiplied by the difference between the normal calendar month degree days and the normal billing month degree days to calculate the cycle billing adjustment.

Q. WHAT IS THE LEVEL OF COMPANY USE GAS PROJECTED DURING THE DETERMINATION PERIOD?

A. Company Use Gas is projected to be 1,591 Mcf for this determination period. This projection is approximately the same level of volume experienced by the Company during the actual twelve months ended June 30, 2013.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED UNACCOUNTED FOR GAS AS SET FORTH IN SCHEDULE C.1.

A. An unaccounted for gas volume of 73,672 Mcf has been projected for the twelve months ending October 31, 2014. Unaccounted for gas is calculated by multiplying the respective sales volumes for each month by 3.59% and subtracting the estimated Company Use and Pressure Compensation for the month. The 3.59% utilized in this GSR calculation includes volumes attributed to metering pressure differential and is representative of five-year history of unaccounted for gas volumes. The use of a five year history of unaccounted for gas volumes was approved by the Public Service Commission by Order No. 4189 in PSC Docket No. 95-206.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED PRESSURE COMPENSATION VOLUMES AS SET FORTH IN SCHEDULE C.1.

A. The pressure compensation projection of 53,617 Mcf is calculated by multiplying the total projected Mcf sales by the factor 0.0149355. This factor represents the calculation used to pressurize gas received from Eastern Shore to a standard pressure of 14.73 PSI for delivery on the Company's distribution system.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED COST OF FIRM SALES FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2014.

A. The projected cost of firm sales is detailed on a monthly basis throughout the seven pages of Schedule C.2. In calculating the proposed cost of gas for the period November 1, 2013 through October 31, 2014, the total projected supply requirements were allocated between the different categories of gas (commodity and storage) available to meet the projected demand. Pages 1 and 2 of Schedule C.2 primarily calculate the fixed costs of firm transportation on Columbia Gas Transmission ("Columbia"), Columbia Gulf Transmission ("Columbia Gulf"), Transcontinental Gas Pipe Line ("Transco"), Eastern Shore, and Texas Eastern Transmission ("TETCO"). A summary of storage demand and capacity charges is also included on these two pages. Pages 3, 4 and 5 calculate the gas commodity costs associated with firm transportation service. As summarized on Page 4 of Schedule C.2, the projected cost of storage gas commodity for withdrawals during this period has been calculated using the actual purchases and costs for the months of April 2013 through July 2013 and projected purchases and costs for August 2013 through October 2013. The twelve-month period ending March 2014 is used for the calculation of the storage gas demand cost to properly reflect the amounts to be expensed during the determination year. The rates used in the commodity gas purchase projections for flowing commodity gas for November 2013 through October 2014 are based on natural gas commodity futures market prices during the first week of August 2013, as well as any gas that had been previously purchased under the Company's "Natural Gas Commodity Procurement Plan" for this determination period.

Q. PLEASE EXPLAIN THE CHANGE IN THE PROJECTED FIRM COST OF GAS FOR THE TWELVE MONTHS ENDING OCTOBER 31, 2014 AS SHOWN ON

SCHEDULE F COMPARED TO NINE MONTHS OF ACTUAL COSTS AND THREE MONTHS OF PROJECTED COSTS FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2013.

A. Schedule F compares the projected firm cost of gas for the twelve months ending October 31, 2014 utilized in this proceeding to the nine months of actual gas costs and three months of projected gas costs for the twelve-month period ending October 31, 2013. In addition, for informational purposes, the actual firm cost of gas for the three prior determination periods ended October 2012, 2011, and 2010 are shown. Chesapeake anticipates a decrease in firm gas costs per Mcf from $10.6827 per Mcf to $10.4854 per Mcf or a $0.1973 per Mcf decrease for the twelve months ending October 31, 2014. As indicated on Schedule F, the $0.1973 per Mcf decrease is mainly attributable to an increase in the total firm sales projected for the twelve months ended October 31, 2014.

Q. PLEASE EXPLAIN SCHEDULES D.1 AND D.2 IN THIS GSR FILING.

A. Schedule D.1 sets forth the calculation of the purchased gas over/under collection by month for the twelve-month period ending October 31, 2013. The projected under collection balance at October 31, 2013 that is carried forward into this annual filing is $1,814,832.

Schedule D.2 reflects the shared margins over/under refund for the twelve-month determination period ending October 31, 2013. Based on this twelve-month determination period, the Company's under refunded shared margins are

$332,372. This amount is also included in the shared margin calculation on Schedule A.2.

Q. PURSUANT TO THE PROVISIONS OF THE TARIFF CONCERNING THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM APPROVED BY ORDER NO. 3648, THE COMPANY AS PART OF ITS ANNUAL GSR FILING IS REQUIRED TO PROVIDE THE COMMISSION STAFF WITH ACTUAL UNACCOUNTED FOR GAS VOLUMES FOR THE PRECEDING TWELVE MONTH PERIOD ENDED JULY 31. HAS THE COMPANY INCLUDED A SCHEDULE SHOWING THE REQUIRED INFORMATION?

A. Yes. Schedule G represents the actual unaccounted for gas volumes for the twelve months ended July 31, 2013.

Q. WHAT WERE THE UNACCOUNTED FOR GAS TARGET PERCENTAGE AND DEAD BAND PERCENTAGES APPROVED FOR THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM IN PSC DOCKET NO. 92-87F?

A. The Unaccounted For Gas Target approved was 3.20% of total gas sendout or total gas requirements. The Dead Band approved was +/- 0.5% points around the 3.20% target level. Unaccounted For Gas Volumes that are within 2.70% to 3.70% of total gas sendout are considered to be within this band and meeting the objectives of this mechanism.

Q. WHAT WAS THE ACTUAL LEVEL OF UNACCOUNTED FOR GAS VOLUMES FOR THE TWELVE MONTHS ENDED JULY 31, 2013 COMPARED TO THE INCENTIVE MECHANISM TARGETS?

A. The actual unaccounted for gas percentage, as established by the approved guidelines in PSC Docket No. 92-87F, for the twelve months ended July 31, 2013, was 0.72% of total gas requirements. This percentage is under the targeted percentage of 3.20% and is also under the dead band range of 2.70% to 3.70%.

Q. EARLIER IN THIS TESTIMONY YOU MENTIONED THAT YOU WERE PROPOSING A CHANGE TO THE DELAWARE DIVISION'S FIRM BALANCING RATES FOR TRANSPORTATION CUSTOMERS BEING SERVED UNDER RATE SCHEDULES "LVS" AND "HLFS". PLEASE EXPLAIN WHY THE CHANGES TO THE GAS SALES SERVICE RATES AND THE BALANCING RATES ARE BEING PROPOSED IN THE SAME DOCKET.

A. Chesapeake's firm transportation balancing rates are calculated in accordance with the methodology approved in PSC Docket No. 95-73, Phase II, by Order No. 4400 and are based on Chesapeake's annual purchased gas costs. As a result of this order, Chesapeake is required to update its balancing rates for Rate Schedules "LVS" and "HLFS" on an annual basis at the time of its annual Gas Sales Service Rate application. Chesapeake also agreed to update its balancing rate for "ITS" during its annual Gas Sales Service application as a result of Order No. 7434 issued on September 2, 2008 in PSC Docket No. 07-186.

The relationship between the GSR charges and the transportation balancing rates exist because the gas costs being presented in this GSR filing are the same gas costs that are used to calculate the transportation balancing rates.

Q. PLEASE STATE THE BALANCING RATES THAT ARE BEING PROPOSED IN THIS FILING.

A. Chesapeake is proposing an increase in the current firm balancing rate for transportation customers served under Rate Schedule "LVS" from $0.063 per Ccf to $0.072 per Ccf to be effective for service rendered on and after November 1, 2013. The Company is proposing a decrease in the firm balancing rate for transportation customers served under Rate Schedule "HLFS" from $0.022 per Ccf to $0.015 per Ccf to be effective for service rendered on and after November 1, 2013. The Company is proposing no change to the current interruptible balancing rate for transportation customers served under Rate Schedule "ITS" of $0.001 per Ccf.

Q. WHAT IS THE PRIMARY REASON FOR THE CHANGES IN THE BALANCING RATES THAT ARE BEING PROPOSED?

A. The primary reason for the decrease in the firm balancing rate for transportation customers served under Rate Schedule "HLFS" is an increase in the annual load factor for the class from 50.23% in the last filing to 60.83% as shown on Schedule J. The primary reason for the increase in the firm balancing rate for transportation customers served under Rate Schedule "LVS" is the increase in the average design day cost per Dt for the fixed gas supply resources from $0.6023 to $0.6936.

Q. WHAT GAS SUPPLY RESOURCES IS THE COMPANY USING IN DEVELOPING THE BALANCING SERVICE RATES BEING SUBMITTED IN THIS FILING?

A. Schedule J, Page 1 of 4 shows the Delaware Division's gas supply resources being used in developing the balancing service rates along with the purchased gas costs associated with these gas supply resources. All of these resources provide firm deliveries that vary in daily entitlements and duration.

Q. PLEASE BRIEFLY EXPLAIN HOW THE OVERALL COSTS OF THE GAS SUPPLY RESOURCES WERE DEVELOPED ON SCHEDULE J.

A. The Delaware Division's gas costs associated with the gas supply resources for balancing services are based on the same costs contained in the development of the GSR charges. The gas supply resources and their costs are separated into fixed gas supply resources and variable gas supply resources. The Delaware Division's storage demand and capacity, and propane peak shaving facilities are related to the fixed gas supply resources, while storage injection and withdrawal volumes are related to the variable gas supply resources.

Q. HOW WAS THE AVERAGE ANNUAL RATE OF APPROXIMATELY $133.30 PER DT FOR THE FIXED GAS SUPPLY RESOURCES DETERMINED ON SCHEDULE J, PAGE 1 OF 4?

A. The gas costs were determined for each of the fixed gas supply resources to be used by the Company in performing this balancing service. The total annualized gas supply costs of $3,629,124 were divided by the daily entitlements of 27,225 Dts to derive the annual amount of $133.3012 per Dt for these fixed gas supply resources in the balancing service.

Q. HOW WAS THE COST OF THE VARIABLE GAS SUPPLY RESOURCES DETERMINED IN THIS PROCEEDING?

A. The overall variable rate of $0.0109 per Dt was determined based on the current storage injection and withdrawal capacities of the Delaware Division's storage resources. This rate was cut in half to arrive at separate rates for injections and withdrawals. This is important because a transportation customer on any given day will either over deliver (the Company would inject the excess gas into storage) or under deliver (the Company would withdraw from storage to meet the demand) the customer-owned gas into the system on the customer's behalf. The resulting rate used for the variable gas supply component of the balancing services is $0.0109 per Dt.

Q. WERE THESE OVERALL FIXED GAS SUPPLY RESOURCE COSTS AND VARIABLE GAS SUPPLY RESOURCE COSTS UTILIZED IN THE DEVELOPMENT OF THE BALANCING SERVICE RATES?

A. Yes. The variable gas supply rate was used as the basis for the variable component in developing the balancing service rates. The fixed gas supply rate will differ between the balancing services due to the specific nature of the service being provided and the fact that the balancing rate is charged on consumption, not just the imbalance volumes. The fixed gas supply portion of the balancing service rates is based on specific load factors along with the percentage of the Company's gas supply needed to balance the requirements of specific customer class requirements. This percentage of the Company's gas supply will be the difference between their average day requirements and design day requirements.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR LARGE VOLUME SERVICE DEVELOPED?

A. Schedule J, Page 2 of 4 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $133.3012 per Dt based on the Large Volume load factor of 24.02%. This load factor resulted in an average cost of $1.5148 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 54.21% of the peak day requirements, the Company would need to supply the remaining 45.79% with its gas supply resources. In other words, these firm customers would pay for 45.79% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 45.79% would be approximately $0.6936 per Dt applicable to all consumption. The variable commodity rate of $0.0109 per Dt was multiplied by the estimated imbalance volume percentage of 17.41% to derive the variable rate of $0.0019 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 2 of 4. The resulting balancing rate for the LVS rate schedule is $0.072 per Ccf.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR HIGH LOAD FACTOR SERVICE DEVELOPED?

A. Schedule J, Page 3 of 4 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $133.3012 per Dt based on the High Load Factor Service load factor of 60.83%. This load factor resulted in an average cost of $0.6005 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 76.33% of the peak day requirements for this class, the Company would need to supply the remaining 23.67% with its gas supply resources which the transportation customers would pay for through the balancing service rate. The resulting rate for the fixed capacity based on this 23.67% would be approximately $0.1421 per Dt applicable to all consumption. The variable commodity rate of $0.0109 per Dt was multiplied by the estimated imbalance volume percentage of 3.50% to derive the variable rate of $0.0004 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 3 of 4. The resulting balancing rate for the HLFS rate schedule is $0.015 per Ccf.

Q. WHAT ABOUT THE BALANCING RATE FOR INTERRUPTIBLE CUSTOMERS?

A. Schedule J, Page 4 of 4 shows the development of the balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $133.3012 per Dt based on the Interruptible Transportation Service load factor of 100%. This load factor resulted in an average cost of $0.3652 per Dt. The rate for the fixed capacity based on average cost at 1.00% would be approximately $0.0037 per Dt applicable to all consumption. The variable commodity rate of $0.0109 per Dt was multiplied by the estimated imbalance volume percentage of 11.11% to derive the variable rate of $0.0012 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 4 of 4. The resulting balancing rate for the ITS rate schedule is $0.001 per Ccf, which is the current rate for this customer class. Accordingly, no change is being proposed.

Q. DOES THE COMPANY'S APPLICATION CONTAIN ADDITIONAL INFORMATION IN ORDER TO COMPLY WITH PRIOR COMMISSION ORDERS?

A. Yes. The Company's filing contains support in compliance with Commission Orders issued over the past few years which I will discuss in greater detail.

Q. AS A RESULT OF THE SETTLEMENT AGREEMENT REACHED IN PSC DOCKET NO. 12-450F, WHAT INFORMATION WAS THE COMPANY TO INCLUDE IN THIS FILING?

A. As a result of the settlement agreement in the last GSR proceeding, the Company agreed to the following as part of this GSR application process:

1) The Company agreed that the margin sharing mechanism related to the capacity valuation credit received from the Asset Manager would be modified so that Chesapeake would retain seven and one-half percent (7.5%) of the credits received by the Asset Manager, and credit the remaining ninety two and one-half percent (92.5%) to the GSR rates, effective June 1, 2013.
2) Chesapeake shall be allowed to continue to recover the Texas Eastern capacity costs and the ESNG capacity costs associated with the Texas Eastern interconnect. With respect to any capacity release revenues received outside of an Asset Management Agreement associated with this capacity, one hundred percent (100%) of any capacity release revenues associated with the release of this capacity will be credited to the GSR.

3) The Company agreed that no part of any fees paid to Planalytics, Inc. for the use of their EnergyBuyer software in connection with the Company's pilot hedging program will be recovered in the Company's GSR rates and that a true-up would be made in this year's GSR Application to offset the costs of $50,000 included in the prior year's GSR filing.

4) At the time of the last GSR filing, the Company experienced an increase in the unaccounted-for-gas cost ("UFG"). The Company agreed to continue to investigate the source(s) of the prior increase in UFG and file with the Commission a written report of the Company's final findings on or before the date on which the Company files its next GSR application.

5) The Company agreed to submit a regulatory filing on or before October 1, 2013, in which the Company will propose changes to its current transportation program mechanics for commercial and industrial customers and which will propose an alternative approach regarding the allocation of the cost of upstream pipeline capacity to transportation customers.

6) As agreed in prior dockets, the Company will continue with the following practices: (a) the Company will notify the parties of any supplier refunds that may impact the GSR charges; (b) the Company will continue to include in future GSR applications an update on steps taken to mitigate the effects of changes in gas costs; (c) the Company will provide information on the total sales volumes, costs, and margins by month for Interruptible Gas Transportation sales as part of its GSR applications; and (d) the Company will calculate the impact on its proposed GSR rates had a thirty-year average degree days been used and provide such

information to the Staff and DPA as part of the discovery process, when and if requested.

Q. HAS THE COMPANY COMPLIED WITH THE SETTLEMENT PROVISIONS AS PART OF THIS GSR APPLICATION PROCESS?

A. Yes. With respect to the first item listed concerning the change in the Company's margin sharing mechanism for the capacity valuation credit received from its Asset Manager, the Company began crediting ninety two and one-half percent (92.5%) to firm sales customers through the GSR in June 2013. Schedule D.2 shows this change for the months June 2013 through October 2013; Schedule A.2 shows the projected amount of margin sharing for the upcoming determination period which is expected to be $1,965,625.

With respect to the second item listed, the Company has not projected any capacity release revenues associated with the Texas Eastern capacity for the GSR period that is to be received outside the Asset Management Agreement. However, any future capacity release revenues associated with this capacity that are received outside of an Asset Management Agreement will be credited 100% to the ratepayers through the margin sharing mechanism.

With respect to the third item listed, the Company has included a true-up on Schedule B that removes the $50,000 cost of the Planalyics, Inc. EnergyBuyer software that was included in the prior year's GSR filing.

With respect to the fourth item listed regarding the Company's level of unaccounted-for gas, the Company has been continuing its investigation into the cause(s) of the increase in the levels of unaccounted-for gas experienced at the time of the prior year's GSR filing. The Company will be filing a report, concurrently with this GSR application and under separate cover, on its investigation and some of the steps it has taken to remedy the situation to bring the level of unaccounted-for gas to a more acceptable level.

With respect to the fifth item listed, the Company will be making a regulatory filing, as described, on or before October 1, 2013

Q. PLEASE ADDRESS THE REMAINING SETTLEMENT PROVISION ITEMS FROM THE LAST GSR TO BE COVERED IN THIS APPLICATION.

A. With respect to supplier refunds, the Company has included an estimate of $435,000 related to a pending Transco refund based on its most recent rate case filed with FERC. With respect to gas cost change mitigation measures, the Company continues to encourage its customers to enroll in its budget billing program. The program provides for even monthly payments for the period of September through May. If necessary, these monthly payments are adjusted midway through the winter in an attempt to avoid large credit or debit balances at the end of the budget period. The Company has included messages on its customers' bills during the summer months, encouraging customers to sign up for the program which begins in September. Additionally, the Company continues to promote conservation by including conservation tips on its customers' bills, as part of its customer guides (which are sent to each residential customer prior to every winter), and on a pamphlet made available in its Dover office.

Q. AS A RESULT OF THE SETTLEMENT AGREEMENT REACHED IN PSC DOCKET NO. 09-398F, WHAT INFORMATION WAS THE COMPANY TO INCLUDE IN THIS FILING?

A. As a result of the settlement agreement in that GSR proceeding, the Company agreed to include the following provision:

1) Effective November 1, 2010, the Settling Parties agreed to a margin sharing mechanism whereby Chesapeake retains 100% of the interruptible transportation margins up to $575,000, (the amount included in Chesapeake's currently authorized firm base rates). Chesapeake will also retain 100% of the next $100,000 of interruptible transportation margins. Thereafter, Chesapeake will credit to the GSR 90% of interruptible transportation margins over $675,000, with the Company retaining 10% of margins over $675,000.

Q. PLEASE EXPLAIN HOW THE COMPANY COMPLIED WITH THE MARGIN SHARING SETTLEMENT PROVISIONS FROM PSC DOCKET NO. 09-398F?

A. For the determination period ending October 2013, the Company's projected level of interruptible margins is not expected to exceed the threshold whereby margin would be shared; however if actual interruptible margins received exceed

$675,000 during the determination period, the Company will share those margins with the firm ratepayers according to the margin sharing mechanism.

Q. HAS THE COMPANY PROVIDED TOTAL SALES VOLUMES, COSTS, AND MARGINS BY MONTH FOR ITS INTERRUPTIBLE TRANSPORTATION CUSTOMERS?

A. Yes. The settlement agreement in PSC Docket No. 08-269F (where Chesapeake first agreed to provide this information) allowed for this schedule to be submitted under a separate cover, as it contains confidential commercial and financial information. Therefore, the Company will be submitting this detail under a separate cover letter.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: SEPTEMBER 3, 2013

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF SARAH E. HARDY

SARAH E. HARDY, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Sarah E. Hardy"; that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Sarah E. Hardy

Sarah E. Hardy

Then personally appeared this 3rd day of September 2013 the above-named Sarah E. Hardy and acknowledged the foregoing Testimony to be her free act and deed. Before me,

REBECCA S. KILLEN NOTARY PUBLIC MY COMMISSION EXPIRES ON 08-07-14 STATE OF DELAWARE

Rebecca S. Killen

Notary Public
My Commission Expires: 8-7-14